ORTH CAROLINA DIVISION OF AIR QUALITY

Application Review

Issue Date:

Region: Mooresville Regional Office
County: Gaston
NC Facility ID: 3600039
Inspector's Name: Joseph Foutz
Date of Last Inspection: 06/08/2016
Compliance Code: 3 / Compliance - inspection

Facility Data

Applicant (Facility's Name): Duke Energy Carolinas, LLC - Allen Steam Station

Facility Address:
Duke Energy Carolinas, LLC - Allen Steam Station
253 Plant Allen Road
Belmont, NC 28012

SIC: 4911 / Electric Services
NAICS: 221112 / Fossil Fuel Electric Power Generation

Facility Classification: Before: Title V **After:** Title V
Fee Classification: Before: Title V **After:** Title V

Permit Applicability (this application only)

SIP: 15A NCAC 02D .0521, .0536, .0606, .0612, 02Q .0306(a)(11), 02Q .0501(d)(1)
NSPS: NA
NESHAP: Subpart UUUUU
PSD: NA
PSD Avoidance: 15A NCAC 02Q .0317
NC Toxics: NA
112(r): NA
Other: NA

Contact Data

Facility Contact	Authorized Contact	Technical Contact
M. Randy Gantt Environmental Coordinator (704) 829-2587 253 Plant Allen Road Belmont, NC 28012	P. Brent Dueitt General Manager II (704) 829-2400 253 Plant Allen Road Belmont, NC 28012	William Horton Lead Environmental Specialist (980) 373-3226 526 South Church Street Charlotte, NC 28202

Application Data

Application Number: 3600039.15A
Date Received: 01/27/2015, 07/14/2015 & 05/31/2016
Application Type: Modification
Application Schedule: TV-Significant

Existing Permit Data

Existing Permit Number: 03757/T40
Existing Permit Issue Date: 01/13/2015
Existing Permit Expiration Date: 12/31/2019

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2015	1127.94	2682.31	21.27	353.68	178.19	20.96	17.92 [Hydrogen chloride (hydrochlori]
2014	1718.20	4018.53	29.88	984.77	291.49	28.98	24.87 [Hydrogen chloride (hydrochlori]
2013	846.27	3155.95	25.31	884.92	322.22	29.05	23.95 [Hydrogen chloride (hydrochlori]
2012	707.34	2296.93	25.18	864.71	242.38	33.19	27.49 [Hydrogen chloride (hydrochlori]
2011	1665.32	4401.64	53.38	1804.34	534.51	71.32	59.09 [Hydrogen chloride (hydrochlori]

Review Engineer: Ed Martin

Review Engineer's Signature: **Date:**

DRAFT FOR PUBLIC NOTICE

Comments / Recommendations:
Issue 03757/T41
Permit Issue Date:
Permit Expiration Date:

I. Purpose of Application:

This review covers the following requests from Duke Energy Carolinas - Allen Steam Station:

Application 3600039.15A
The following permit modifications were requested by Duke Energy in this application:

1. PM CEMS Option
   To add provisions on Units 1-5 to use a PM continuous emission monitor system (CEMS) as an option to the current method of using a Continuous Opacity Monitor System (COMS) and particulate emissions monitoring for compliance with 02D .0521 (opacity), 02D .0536 (particulate and annual average opacity), and 02D .0606 as discussed below. This is in preparation for the Utility Boiler Mercury Air Toxics Standards (MATS) rule which became effective April 16, 2016, and is also being incorporated into the permit at this time (see 2 below).

2. Incorporation of MATS Rule Requirements into the Permit
   To incorporate the requirements of the Maximum Achievable Control Technology (MACT) as promulgated in the most current version of 40 CFR Part 63 Subpart UUUUU, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units" (also known as the Mercury And Toxics Standards (MATS rule).

Application 3600039.15D (consolidated into application 3600039.15A)
This application is requesting the use of mercury oxidation fuel additives (halide salt or equivalent additives) applied to the incoming coal to reduce mercury emissions in order to comply with the MATS rule emission limits.

Application 3600039.16C (consolidated into application 3600039.15A)
This is the Title V Air Quality Permit Application (second-step of the Title V permitting process) for the air emission sources ID Nos. ES-EmQP, ES-EmFP, and ES-EmGenMWT in Section 2.1.G. Footnote 2 to the Section 1 table of permitted emission sources requiring the Permittee to file a Title V Air Quality Permit Application for these sources on or before 12 months after commencing operation was removed.

This is a significant Title V permit modification pursuant to rule 15A NCAC 02Q .0501(d)(1) because the PM CEMS alternate compliance provisions requested in application 3600039.15A require public notice at this time. Duke was informed that the halide salt application (3600039.15D) they had requested be a TV-Minor application must be either a TV-Significant one-step or two-step with public notice 12 months later. Since the default is to process TV-Significant applications as a two-step process, Duke was requested to notify DAQ if they agreed to process the halide salt application together with application 3600039.15A, which must go through public notice at this time, in the interest of being more efficient for DAQ and Duke and to avoid the second-step application 12 months later. Duke provided their authorization to process this application with application 3600039.15A using the one-step process in an email dated December 15, 2016 from Bill Horton with including an email from the Responsible Official Brent Dueitt.

II. Chronology for Application 3600039.15A

January 26, 2015 (received Jan 27, 2015)	Original application requesting the use of PM CEMS based on the regulatory framework in 40 CFR 60 D and Da (NSPS).
February 26, 2015 (received Feb 27, 2015)	Duke amended the application to: (1) use the 40 CFR 63 UUUUU MATS rule as the regulatory framework for the PM CEMS rather than 40 CFR 60 D and Da (NSPS), (2) to incorporate the 40 CFR 63 Subpart UUUUU MATS rule requirements into the permit, and (3) incorporate the MATS 1-year compliance extension into the permit.

II. Permit Changes

The following changes were made to the Duke Energy Carolinas LLC – Allen Steam Station Air Permit No. 03757T40:

Page No.	Section	Change
Cover	--	Amended permit numbers and dates.
--	Insignificant Activities List	Added I-80. Removed I-2, I-31, I-44, I-46, I-54, I-61, I-68, I-74, I-78, and I-79. Revised I-3, I-33, I-35, and I-76.
3-4	Section 1, table of permitted emission sources	Added MACT UUUUU designation for Units 1-5.
		Added halide salt mercury oxidation fuel additives to Units 1-5 (ES-1 through ES-5) emission source description.
		Removed old footnote 2 since a Title V Air Quality Permit Application (3600039.16C) for the air emission sources (ID Nos. ES-EmQP, ES-EmFP, and ES-EmGenMWT) was filed and included in this permit modification. Added new footnote 2 for incidental spills of oil, antifreeze, etc. Removed footnote † since the injection of powdered activated carbon (ID No. CD-U4/5ActC), emission source ID Nos. ES-U4/5ACISilo, and control device CD-U4/5ACISiloBf, originally permitted as a minor modification per 15A NCAC 02Q .0515, are now going through the Title V permitting process.
8	Section 2.1.A, equipment description	Added halide salt mercury oxidation fuel additives for Units 1-5 (ES-1 through ES-5).
8-11	Section 2.1.A, regulation table	Revised 02D .0521 limits for alternate PM CEMS monitoring option.
		Revised 02D .0536 PM limits for alternate PM CEMS monitoring option.
		Added 02D .0614 CAM (40 CFR 64) which was inadvertently omitted from previous permits and specified that it applies for periods when COMS are used.
		Added applicable regulation 15A NCAC 02D .1111 (40 CFR 63 Subpart UUUUU).
		Added 15A NCAC 02Q .0317 [PSD AVOIDANCE] for PM/PM10/PM2.5 in Section 2.1.A.12.
		Added 15A NCAC 02Q .0317 [PSD AVOIDANCE] for PM2.5 in Section 2.1.A.14.
		Added footnote * to table for alternate PM CEMS monitoring option.
13	Section 2.1.A.3	Revised 02D .0521 to add alternate PM CEMS monitoring option.
14-15	Section 2.1.A.4	Revised 02D .0536 and 02Q .0317(a)(1) to add alternate PM CEMS monitoring option.
14	Section 2.1.A.4.e	Revised to allow the use of MATS Method 5 to demonstrate compliance with the 02D .0536 stack test requirement.
15-17	Section 2.1.A.5	Revised language in Section 2.1.A.5.i.

		Revised state-only 02D .0536 to add alternate PM CEMS monitoring option.
17-18	Section 2.1.A.7	Revised 02D .0606 to add alternate PM CEMS monitoring option.
19	Section 2.1.A.11	Added language to indicate 02D .0614 applies only during periods when using the alternate COMS monitoring option.
22-28	Section 2.1.A.15	Added this section for the MACT Subpart UUUUU requirements.
28-29	Section 2.1.A.16	Added this PSD avoidance condition for emissions from applying halide salt mercury oxidation fuel additives.
46	Section 2.1.H, equipment description	For the Units 4 and 5 DSI ACI storage silo (ID No. ES-U4/5ACISilo) and associated Units 4 and 5 ACI storage silo bin vent filter baghouse (ID No. CD-U4/5ACISiloBf): Removed non-shielded statement since this equipment is now going through the Title V permitting process. Removed the state-only start-up notification requirement since notification has been made.
60-68	Section 3.0	Updated general conditions to version 4.0 12/17/15.

III. Facility Description

Duke Energy's Allen Steam Station is an electric utility that generates electrical power. The Allen Steam Station is permitted for five coal/No. 2 fuel oil-fired electric utility boilers (ID Nos. ES-1 (U1 Boiler), ES-2 (U2 Boiler), ES-3 (U3 Boiler), ES-4 (U4 Boiler), and ES-5 (U5 Boiler)), one No. 2 fuel oil-fired auxiliary boiler (ID No. ES-6 (AuxB)), and other supporting ancillary sources.

IV. Summary of Changes to Emission Sources and Control Devices

A. Added MACT UUUUU designation for Units 1-5 (ES-1 through ES-5) in the Section 1 table of permitted emission sources.

B. Added halide salt mercury oxidation fuel additives to Units 1-5 (ES-1 through ES-5) source description in the Section 1 table of permitted emission sources and in the Section 2.1.A equipment description.

V. Emission and Regulatory Evaluation

A. PM CEMS Option

Duke is requesting a change to allow provisions on Units 1-5 to use a PM continuous emission monitoring system (CEMS) as an alternate option to the current method of using a Continuous Opacity Monitoring System (COMS) and particulate emissions monitoring. The permit changes to allow for the use of a PM CEMS, as an option to using COMS. The change consists of revising the monitoring, recordkeeping and reporting conditions for compliance with rules 15A NCAC 02D .0521 (opacity in Section 2.1.A.3), 02D .0536 (particulate and annual average opacity in Sections 2.1.A.4 and 5) and 02D .0606 (Appendix P of 40 CFR Part 51 good O&M in Section 2.1.A.7). Duke's original application request for the PM CEMS option for these SIP (non-NSPS) units was based on the NSPS Subpart D and Da PM CEMS certification and operation requirements; however, in a letter dated February 26, 2015, Duke amended the application to request the PM CEMS option be based on the MATS rule requirements instead of the NSPS rules, as discussed later in this review. This was in preparation for the Utility Boiler Mercury Air Toxics Standards (MATS) rule for which existing EGUs such as Allen must comply with no later than April 16, 2015 (see Section V.B below).

This change is similar to the changes previously or to be made for all of Duke's fleet of SIP boilers. Previously, this change has been made at Roxboro Units 1, 2 and 3; and for Belews Creek Units 1 and 2 (which were in turn based on previous changes made for the NSPS Subpart D boilers at Roxboro Unit 4 and Mayo Unit 1).

In accordance with 15A NCAC 02D .0612, the owner or operator of a source may petition the Director to allow monitoring or data reporting procedures varying from those prescribed by a rule of 15A NCAC 02D or 02Q. Since the use of PM CEMS is not specified as a compliance method in the applicable NC rules, Duke originally petitioned DAQ to be allowed to install and use a PM CEMS based on the NSPS provisions as an alternative to using COMS for monitoring opacity emissions and now has again petitioned to use PM CEMS based on the MATS provisions because these units are now subject to the MATS rule (see Section V.B below). Duke revised the application on February 26, 2015, to request the regulatory framework for the PM CEMS option be based on the MATS rule requirements instead of the NSPS rules, in part to streamline and simplify the permit conditions by reducing overlapping requirements. Duke made their petition for alternative monitoring, to use a PM CEMS based on the MATS provisions in a letter dated February 25, 2015, to Mr. Michael Pjetraj. DAQ approved the MATS-based petition in a letter to Mr. Paul B. Dueitt (Allen Responsible Official at that time) from Lee Daniel, SSCB, dated June 25, 2015, which outlines guidance for using the PM CEMS based on MATS.

The permit changes to allow for the use of PM CEMS based on the MATS rule consist of revising 02D .0521 (opacity) in Section 2.1.A.3, 02D .0536 (particulates) in Section 2.1.A.4, 02D .0536 (annual average opacity) in Section 2.1.A.5, and 02D .0606 (Appendix P of 40 CFR Part 51, good O&M) in Section 2.1.A.7. These changes for periods when the PM CEMS option is used are as follows:

<u>02D .0521 (opacity)</u>
Under the MATS rule, opacity monitoring is not required at the very low MATS rule PM limit of 0.030 pounds per million Btu heat input (or 0.30 pounds per MWh), and has been removed from the 02D .0521 monitoring in Section 2.1.A.3.

<u>02D .0536 (particulates)</u>
As part of the agreement with SSCB, emissions of particulate matter from Units 1-5 when the PM CEMS are used were reduced from the 02D .0536(b) limit of 0.25 lb/mmBtu for Units 1 and 2, and the 02Q .0317(a)(1) PSD avoidance limit of 0.20 lb/mmBtu for Units 3, 4 and 5, to 0.030 pounds per million Btu heat input (30-boiler operating day rolling average) or 0.30 pounds per MWh (30-boiler operating day rolling average) for compliance.

The PM CEMS requirements in 02D .0536 are consistent with the MATS rule monitoring option using PM CEMS selected by Duke - one of three PM compliance options under MATS (ie: either a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly). The monitoring, recordkeeping and reporting under 02D .0536 has been revised to include and cross-reference the applicable MATS requirements in permit conditions 2.1.A.15.dd, ff and tt.

The PM emission rate shall be determined based on a 30-boiler operating day rolling average of the hourly arithmetic average emissions concentrations using the CEMS outlet data for each boiler operating day (as defined below), except for data obtained during periods of startup or shutdown. Periods of malfunction shall be included in the emissions calculations.

<u>02D .0536 (AAO)</u>
In addition, in order to comply with the Annual Average Opacity (AAO) requirements of 02D .0536(b) during periods of operation when the PM CEMS option is used in place of the COMS, Method 9 opacity readings are taken during the PS-11 testing to correlate opacity with PM emissions. This provides a method to continuously calculate opacity based on the PM CEMS output during operation when the COMS are not used (see Equation 1 below). Method 9 is used instead of the COMS, because the COMS do not reflect the true opacity exiting the stack. The COMS, being upstream of the scrubber, do not account for PM taken out in the scrubber and therefore read much higher than the

actual opacity at the stack. In addition to providing a more accurate opacity, the Method 9 readings are particularly necessary when attempting to achieve the mid and high dust loads in the ESP required during PS-11 testing to cover the full range of opacity to be encountered during normal operation. At these high dust loads, the COMS, even though reading high, would not normally be above the 02D .0521 limit of 40% at typical dust loadings but would most likely be greater than the 02D .0521 limit at the mid and high dust loadings required during testing.

Using the data gathered during PS-11 testing, the opacity can then be calculated as follows:

<u>Equation 1</u>

$$\text{Opacity, average for each hour} = \frac{(\text{Actual PM CEMS Output, average for each hour})(\text{Z, Opacity})}{(\text{Y, mg/m}^3)}$$

where: Y = The average PM CEMS output value (mg/m^3) established during the initial PM CEMS PS-11 certification procedure at or near, but no greater than, the AAO limit. A concurrent Method 9 test shall be conducted during the PM CEMS measurements to determine opacity. At least 60 minutes of PM CEMS and Method 9 data shall be averaged.

Z = The average concurrent Method 9 opacity obtained during the initial PM CEMS PS-11 certification procedure corresponding to the PM CEMS measurements for Y above.

In addition, for periods of less than 365 days of operation using either the COMS option or the PM CEMS option, the AAO shall be calculated as follows:

<u>Equation 2</u>

$$\text{AAO} = \frac{\sum_{i=1}^{Z}(\text{6 minute COMS block i}) + \left(\sum_{j=1}^{Y}(\text{1 hour PM CEMS block j})(\text{10 six} - \text{minute blocks / 1 hour block})\right)}{Z + 10Y}$$

where: Z = number of six-minute COM blocks of data within 365-day look-back period.
Y = number of one-hour PM CEMS blocks of data within 365-day look-back period.

The "1 hour PM CEMS block j" in AAO Equation 2 above is its equivalent 1-hour block opacity as determined from the previous opacity Equation 1 above.

Alternatively, the Permittee may calculate the AAO using valid certified 1 hour PM CEMS blocks of data for the entire 365-day look-back period in the above equation for both the period when using PM CEMS for compliance with the AAO standard (after the 30-day notification) and for the period when using COMS for compliance with the AAO standard (instead of 6 minute COMS blocks).

<u>02D .0606 (good O&M)</u>
For good O&M under 02D .0606, when using PM CEMS, the sources shall be deemed to be properly operated and maintained if the percentage of time the PM emissions, calculated on a one-hour average, greater than the concentration that corresponds to 0.03 lb/mmBtu (21.5 mg/m^3 for Units 1, 2 and 5 Boilers as CS 01 and 21.5 mg/m^3 for Unit 3 and 4 Boilers as CS02; as determined from the initial CEMS certification testing) do not exceed 3.0 percent of the total operating time for any given calendar quarter (this limit is taken from SSCB's approval letter). In addition, the sources shall be deemed to be properly operated and maintained if the %MD does not exceed 2 percent for any given calendar quarter as calculated in Section 2.1.A.7.a of the permit.

When PM CEMS are used for monitoring, the 02D .0614 CAM requirements in Section 2.1.A.11 do not apply since using a CEMS to monitor PM emissions meets the CAM exemption in §64.2(b)(vi) where a Part 70 permit specifies a continuous compliance determination method; therefore, CAM applies only during periods when using the alternate COMS monitoring option.

Duke must submit a written notification to the DAQ of intent to demonstrate compliance by using a CEMS to measure PM as specified in §60.48Da(p)(1). This notification must be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. Duke may discontinue operation of the monitor and instead return to demonstration of compliance using the COMS option by submitting written notification to the DAQ of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

The PM CEMS must meet the requirements of Performance Specification PS-11 of Appendix B of 40 CFR Part 60, <u>Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources</u>. During the initial installation and performance PS-11 procedure, a correlation is made against manual gravimetric reference method measurements (including Methods 5, 5I or 17).

B. <u>Incorporation of MATS Rule Requirements into the Permit</u>

Subpart UUUUU MACT, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units" (MATS rule) applies to any coal-fired EGU or an oil-fired EGU as defined in §63.10042 of this subpart as specified in §63.9981. Certain types of electric steam generating units are not subject to the rule as listed in §63.9983. The current version of this rule was published in 81 FR 20192, Apr. 6, 2016.

The Allen units burn coal and meet the definition of a coal-fired electric utility steam generating unit as defined in §63.10042 as:

Coal-fired electric utility steam generating unit means an electric utility steam generating unit meeting the definition of "fossil fuel-fired" that burns coal for more than 10.0 percent of the average annual heat input during the 3 previous calendar years after the compliance date for your facility in §63.9984 or for more than 15.0 percent of the annual heat input during any one of those calendar years.

Where an electric utility steam generating unit is defined in §63.10042 of the rule as:

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

The Allen units are existing EGUs under the MATS rule since they did not commence construction or reconstruction after May 3, 2011 (§63.9982(d)). An existing EGUs must comply with the MATS rule no later than April 16, 2015 (§63.9984(b)). Duke requested a one-year extension of the compliance date for the MATS standards, as allowed by the rule, in a letter dated October 17, 2014. DAQ approved the request extending the MATS compliance date until April 16, 2016, in a letter dated November 12, 2014. In addition, Duke requested a one-year extension of the compliance date for the MATS work practice standards applicable to startup and shutdown, as allowed by the rule, in a letter dated December 16, 2014, for the Roxboro, Mayo, Belews Creek, Cliffside, Allen and Marshall Stations. NC DAQ approved the request extending the compliance date until April 16, 2016, in a letter to Mr. Larry Hatcher (Vice President, Environmental) from Lee Daniel dated January 14, 2015.

There are two subcategories of EGUs per §63.9990 as defined in §63.10042:

(1) EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb, and
(2) EGUs designed for low rank virgin coal.

The Allen EGUs burn coal with a heating value greater than 8,300 Btu/lb. The requirements are different depending on which subcategory applies.

Emission Limitations and Work Practice Standards

As a coal-fired unit that is not designed for low rank virgin coal, the emission limit options for the Allen EGUs are shown below in accordance with Table 2 to Subpart UUUUU.

Table 2 to Subpart UUUUU of Part 63—Emission Limits for Existing EGUs

As stated in §63.9991, you must comply with the following applicable emission limits:[1]

If your EGU is in this subcategory . . .	For the following pollutants . . .	You must meet the following emission limits and work practice standards . . .	Using these requirements, as appropriate (*e.g.*, specified sampling volume or test run duration) and limitations with the test methods in Table 5 to this Subpart . . .
1. Coal-fired unit not low rank virgin coal	a. Filterable particulate matter (PM)	3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh[2]	Collect a minimum of 1 dscm per run.
	OR		
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR		
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E-1 lb/TBtu[3] or 8.0E-3 lb/GWh	
	Arsenic (As)	1.1E0 lb/TBtu or 2.0E-2 lb/GWh	
	Beryllium (Be)	2.0E-1 lb/TBtu or 2.0E-3 lb/GWh	
	Cadmium (Cd)	3.0E-1 lb/TBtu or 3.0E-3 lb/GWh	
	Chromium (Cr)	2.8E0 lb/TBtu or 3.0E-2 lb/GWh	
	Cobalt (Co)	8.0E-1 lb/TBtu or 8.0E-3 lb/GWh	
	Lead (Pb)	1.2E0 lb/TBtu or 2.0E-2 lb/GWh	
	Manganese (Mn)	4.0E0 lb/TBtu or 5.0E-2 lb/GWh	
	Nickel (Ni)	3.5E0 lb/TBtu or 4.0E-2 lb/GWh	
	Selenium (Se)	5.0E0 lb/TBtu or 6.0E-2 lb/GWh	
	b. Hydrogen chloride (HCl)	2.0E-3 lb/MMBtu or 2.0E-2 lb/MWh	For Method 26A at appendix A-8 to part 60 of this chapter, collect a minimum of 0.75 dscm per run; for Method 26, collect a minimum of 120 liters per run. For

			ASTM D6348-03[3] or Method 320 at appendix A to part 63 of this chapter, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[5]	2.0E-1 lb/MMBtu or 1.5E0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	1.2E0 lb/TBtu or 1.3E-2 lb/GWh	LEE Testing for 30 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B at appendix A-8 to part 60 of this chapter run or Hg CEMS or sorbent trap monitoring system only.
	OR		
		1.0E0 lb/TBtu or 1.1E-2 lb/GWh	LEE Testing for 90 days with a sampling period consistent with that given in section 5.2.1 of appendix A to this subpart per Method 30B run or Hg CEMS or sorbent trap monitoring system only.

[1]For LEE emissions testing for total PM, total HAP metals, individual HAP metals, HCl, and HF, the required minimum sampling volume must be increased nominally by a factor of two.
[2]Gross output.
[3]Trillion Btu
[4]Incorporated by reference, see §63.14.
[5]You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system and SO_2 CEMS installed.

Allen has chosen to comply with MATS by limiting emission as follows:

i. filterable particulate matter (PM) to 3.0E-2 lb/MMBtu or 3.0E-1 lb/MWh (using PM CEMS),
ii. sulfur dioxide (SO_2) to 2.0E-1 lb/MMBtu or 1.5E0 lb/MWh (using SO_2 CEMS), and
iii. mercury (Hg) to 1.2E0 lb/TBtu or 1.3E-2 lb/GWh (using Hg CEMS and/or sorbent trap(s)).

As an alternative to meeting the requirements of §63.9991(a)(1) for filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis as described above, the Permittee may choose to demonstrate compliance by using emissions averaging as described in §63.10009(a)(2) among existing EGUs in the same subcategory. If this option is selected for mercury, the Permittee shall limit the concentration of mercury to 1.0 lb/TBtu or 1.1E-2 lb/GWh. [§63.9991(a)(1), §63.10009 and §63.10022]

Allen has chosen to comply with paragraph (1) of the definition of "startup" in §63.10042. As an existing EGU with no neural network combustion optimization software and not firing syngas, the applicable requirements from Table 3 to Subpart UUUUU are as follows:

During periods of startup of an EGU:
i. The Permittee has chosen to comply using the following work practice standards, by choosing to comply using paragraph (1) of the definition of "startup" in §63.10042, defined as follows.

> *Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup.*

The Permittee shall operate all CMS during startup, except during periods of bypass of the main stack as provided in §63.10010(a)(4). For startup of a unit, clean fuels must be used as defined in §63.10042 for ignition. Once the unit converts to firing coal, the Permittee shall engage all of the applicable control technologies except the SCR. The Permittee shall start the SCR system appropriately to comply with relevant standards applicable during normal operation. The Permittee shall comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in Subpart UUUUU. The Permittee shall keep records during startup periods.

ii. If the Permittee chooses to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, the Permittee shall comply with the limit at all times; otherwise, the Permittee shall comply with the applicable emission limit at all times except for startup and shutdown periods.

iii. The Permittee shall collect monitoring data during startup periods, as specified in §63.10020(a) and (e). The Permittee shall keep records during startup periods, as provided in §§63.10032 and 63.10021(h). The Permittee shall provide reports concerning activities and startup periods, as specified in §63.10011(g) and §63.10021(h) and (i). All periods of bypass of the main stack shall be reported as deviations as provided in §63.10010(a)(4)(ii).
[§63.9991(a)(1) and Table 3 to Subpart UUUUU]

During periods of shutdown of an EGU:

> *Shutdown means the period in which cessation of operation of an EGU is initiated for any purpose. Shutdown begins when the EGU no longer generates electricity or makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes or when no coal, liquid oil, syngas, or solid oil-derived fuel is being fired in the EGU, whichever is earlier. Shutdown ends when the EGU no longer generates electricity or makes useful thermal energy (such as steam or heat) for industrial, commercial, heating, or cooling purposes, and no fuel is being fired in the EGU. Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown.*

i. The Permittee shall operate all CMS during shutdown, except during periods of bypass of the main stack as provided in §63.10010(a)(4). The Permittee shall also collect appropriate data, and shall calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. While firing coal during shutdown, the Permittee shall vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal being fed into the EGU and for as long as possible thereafter considering operational and safety concerns as provided for bypass of the main stack in §63.10010(a)(4). In any case, the permittee shall operate the controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than Subpart UUUUU and that require operation of the control devices. All periods of bypass of the main stack shall be reported as deviations as provided in §63.10010(a)(4)(ii).

ii. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel shall be one or a combination of the clean fuels defined in §63.10042 and shall be used to the maximum extent possible taking into account considerations such as not compromising boiler or control device integrity.

iii. The Permittee shall comply with all applicable emission limits at all times except during startup periods and shutdown periods at which time the Permittee shall meet the work practice standards. The Permittee shall collect monitoring data during shutdown periods, as specified in §63.10020(a). The Permittee shall keep records during shutdown periods, as provided in §§63.10032 and 63.10021(h). The Permittee shall provide reports concerning activities and shutdown periods, as specified in §§63.10011(g), 63.10021(i), and 63.10031.
[§63.9991(a)(1), §63.10042, and Table 3 to Subpart UUUUU]

General Compliance Requirements
The Permittee shall comply with the General Provisions as applicable pursuant to Table 9 to Subpart UUUUU. [§63.10040]

The Permittee shall be in compliance with the emission limits and operating limits in Subpart UUUUU. These limits shall apply at all times except during periods of startup and shutdown; however, for coal-fired EGUs, the Permittee shall be required to meet the work practice requirements in Table 3 to Subpart UUUUU during periods of startup or shutdown. [§63.10000(a)]

At all times, the Permittee shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. [§63.10000(b)]

For coal-fired units, initial performance testing is required for all pollutants for the affected EGUs to demonstrate compliance with the applicable emission limits. [§63.10000(c)(1)]

The Permittee shall demonstrate compliance with the filterable particulate matter (PM) emission limit through an initial performance test and shall monitor continuous performance through use of a PM continuous emissions monitoring system (PM CEMS). [§63.10000(c)(1)(iv)]

The Permittee may demonstrate initial and continuous compliance by installing and operating a sulfur dioxide (SO_2) CEMS installed and operated in accordance with 40 CFR Part 75 to demonstrate compliance with the applicable SO_2 emissions limit. [§63.10000(c)(1)(v)]

The Permittee shall demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system in accordance with Appendix A to the Subpart. [§63.10000(c)(1)(vi)]

As part of demonstration of continuous compliance, the Permittee shall perform periodic tune-ups of the affected EGUs, according to §63.10021(e). [§63.10000(e)]

On or before the date an EGU is subject to Subpart UUUUU, the Permittee shall install, certify, operate, maintain, and quality-assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM during startup periods and shutdown periods. The Permittee shall collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods. [§63.10000(l)]

<u>Continuous Compliance Requirements</u>

The Permittee shall monitor and collect data according to §63.10020. [§63.10020(a)]

The Permittee shall operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see §63.8(c)(7)), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. The Permittee is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable. [§63.10020(b)]

Except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments, failure to collect required data is a deviation from the monitoring requirements. [§63.10020(d)]

The Permittee shall demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 2 and 3 to Subpart UUUUU that applies to the affected EGU, according to the monitoring specified in Table 7 to Subpart UUUUU and paragraphs (b) through (g) of §63.10021(a). [§63.10021(a)]

Except as otherwise provided in §63.10020(c), if the Permittee uses a CEMS to measure SO_2, PM, HCl, HF, or Hg emissions, or uses a sorbent trap monitoring system to measure Hg emissions, the Permittee shall demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. The Permittee shall use Equation 8 to Subpart UUUUU to determine the 30- (or, if applicable, 90-) boiler operating day rolling average.

$$\text{Boiler operating day average} = \frac{\sum_{i=1}^{n} Her_i}{n} \quad (Eq.8)$$

Where:
Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.
[§63.10021(b)]

Conduct periodic performance tune-ups of the EGUs, as specified in paragraphs (e)(1) through (9) of §63.10021. For the first tune-up, the Permittee may perform the burner inspection any time prior to the tune-up or delay the first burner inspection until the next scheduled EGU outage provided the requirements of §63.10005 are met. Subsequently, the Permittee shall perform an inspection of the burner at least once every 36 calendar months unless the EGU employs neural network combustion optimization during normal operations in which case an inspection of the burner and combustion controls shall be performed at least once every 48 calendar months. If the EGU is offline when a deadline to perform the tune-up passes, the tune-up work practice requirements shall be performed within 30 days after the re-start of the affected unit. [§63.10021(e)]

The Permittee shall follow the startup or shutdown requirements as given in Table 3 to the Subpart for each coal-fired EGU and comply with all applicable requirements in §63.10011(g). [§§63.10005(j), 63.10011(g) and §63.10021(h)]

If the Permittee elects to average emissions consistent with §63.10009 for any constituent, following the compliance date, the Permittee must demonstrate compliance on a continuous basis by meeting the requirements of paragraphs (a)(1) through (4) of §63.10022. Any instance where the Permittee fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (3) of §63.10022 is a deviation. [§63.10022]

The Permittee shall determine the fuel whose combustion produces the least uncontrolled emissions, taking safety considerations into account, *i.e.*, the cleanest fuel, either natural gas or distillate oil, that is available on site or accessible nearby for use during periods of startup or shutdown. The cleanest fuel, either natural gas or distillate oil, for use during periods of startup or shutdown determination may take safety considerations into account. [§§63.10011(f)(1) and (2)]

Monitoring
For an affected unit that exhausts to the atmosphere through a single, dedicated stack, the Permittee shall either install the required CEMS and sorbent trap monitoring systems in the stack or at a location in the ductwork downstream of all emissions control devices, where the pollutant and diluents concentrations are representative of the emissions that exit to the atmosphere. [§63.10010(a)(1)]

If the Permittee uses an oxygen (O_2) or carbon dioxide (CO_2) CEMS to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 concentrations shall be monitored at a location that represents emissions to the atmosphere, *i.e.*, at the outlet of the EGU, downstream of all emission control devices. The Permittee shall install, certify, maintain, and operate the CEMS according to 40 CFR Part 75. Use only quality-assured O_2 or CO_2 data in the emissions calculations; do not use Part 75 substitute data values. [§63.10010(b)]

If the Permittee is required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 2 to Subpart UUUUU, the Permittee shall install, certify, operate, and maintain the monitoring system and conduct on-going quality-assurance testing of the system according to 40 CFR Part

75. Use only unadjusted, quality-assured flow rate data in the emissions calculations. Do not apply bias adjustment factors to the flow rate data and do not use substitute flow rate data in the calculations. [§63.10010(c)]

If the Permittee is required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 2 to Subpart UUUUU, the Permittee shall install, certify, operate, and maintain a moisture monitoring system in accordance with 40 CFR Part 75. Alternatively, for coal-fired units, the Permittee may use appropriate fuel-specific default moisture values from §75.11(b) to estimate the moisture content of the stack gas. If the Permittee installs and operates a moisture monitoring system, the Permittee shall not use substitute moisture data in the emissions calculations. [§63.10010(d)]

The Permittee shall use an SO_2 CEMS and must install the monitor at the outlet of the EGU, downstream of all emission control devices, and must certify, operate, and maintain the CEMS according to 40 CFR Part 75 as specified in paragraphs (f)(1) through (4) of §63.10010. [§63.10010(f)]

The Permittee shall use a Hg CEMS or a sorbent trap monitoring system, the Permittee shall install, certify, operate, maintain and quality-assure the data from the monitoring system in accordance with Appendix A to Subpart UUUUU and as specified in §63.10010(g). [§63.10010(g)]

The Permittee shall install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (i)(1) through (5) of §63.10010 (shown below). The compliance limit shall be expressed as a 30-boiler operating day rolling average of the applicable numerical emissions limit value in Table 2 to Subpart UUUUU. [§63.10010(i)]

i. Install and certify the PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using Method 5 at Appendix A-3 to part 60 of this chapter and ensuring that the front half filter temperature shall be 160° ±14 °C (320° ±25 °F). The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).
ii. Operate and maintain the PM CEMS according to the procedures and requirements in Procedure 2—Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.
    (A) Conduct the relative response audit (RRA) for the PM CEMS at least once annually.
    (B) Conduct the relative correlation audit (RCA) for the PM CEMS at least once every 3 years.
iii. Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in §63.10010(i).
iv. Calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler operating hours.
v. Collect data using the PM CEMS at all times the process unit is operating and at the intervals specified in §63.10010(a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.
    (A) Use all the data collected during all boiler operating hours in assessing the compliance with the operating limit except:
    (I) Any data collected during periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of emissions (e.g., calibrations, certain audits). Report any monitoring system malfunctions or out of control periods in the annual deviation reports. Report any monitoring system quality assurance or quality control activities per the requirements of §63.10031(b);
        (II) Any data collected during periods when the monitoring system is out of control as specified in the site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or quality control activities

conducted during out-of-control periods. Report any such periods in the annual deviation report;

(III) Any data recorded during periods of startup or shutdown.

(B) Record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with the site-specific monitoring plan.

Recordkeeping

The Permittee shall keep records of the following:

i. Records required under appendix A and/or appendix B to Subpart UUUUU for continuous monitoring of Hg emissions.
ii. Each notification and report that is submitted to comply with Subpart UUUUU, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that was submitted, according to the requirements in §63.10(b)(2)(xiv).
iii. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in §63.10(b)(2)(viii). [§63.10032(a)]

For each CEMS, the Permittee shall keep records as follows:

i. Records described in §63.10(b)(2)(vi) through (xi).
ii. Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3).
iii. Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).
iv. Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period. [§63.10032(b)]

For each EGU subject to an emission limit, the Permittee shall keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used. [§63.10032(d)(1)]

If the Permittee elects to average emissions consistent with §63.10009 for any constituent, the Permittee must additionally keep a copy of the emissions averaging implementation plan required in §63.10009(f) and(j), all calculations required under §63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with §63.10022. [§63.10032(e)]

If the Permittee chooses to rely on paragraph (1) of the definition of "startup" in §63.10042 for any EGU, records must be kept of the occurrence and duration of each startup or shutdown. [§63.10032(f)(1)]

The Permittee shall keep records of the occurrence and duration of each malfunction of an operation (*i.e.*, process equipment) or the air pollution control and monitoring equipment. [§63.10032(g)]
The Permittee shall keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. [§63.10032(h)]

The Permittee shall keep records of the type(s) and amount(s) of fuel used during each startup or shutdown. [§63.10032(i)]

The Permittee shall keep records in a form suitable and readily available for expeditious review, according to §63.10(b)(1). The Permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. The Permittee shall keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. The Permittee can keep the records off site for the remaining 3 years. [§63.10033(a) through (c)]

Reporting

The Permittee shall submit a Notification of Compliance Status summarizing the results of initial compliance demonstration in §63.10030(e). When the Permittee is required to conduct an initial compliance demonstration as specified in §63.10011(a), the Permittee shall submit a Notification of

Compliance Status according to §63.9(h)(2)(ii). The Notification of Compliance Status report shall contain all the information specified in paragraphs (e)(1) through (8) of §63.10030, as applicable. [§§63.10005(k), 63.10011(e), and 63.10030(e)]

The Permittee shall submit the reports required under §63.10031 and, if applicable, the reports required under appendices A and B to the Subpart. The electronic reports required by appendices A and B to the Subpart shall be sent to the Administrator electronically in a format prescribed by the Administrator, as provided in §63.10031. CEMS data (except for PM CEMS and any approved alternative monitoring using a HAP metals CEMS) shall be submitted using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Other data, including PM CEMS data, HAP metals CEMS data, and CEMS performance test detail reports, shall be submitted in the file format generated through use of EPA's Electronic Reporting Tool, the Compliance and Emissions Data Reporting Interface, or alternate electronic file format, all as provided for under §63.10031. [§63.10021(f)]

The Permittee shall report each instance in which the Permittee did not meet an applicable emissions limit or operating limit in Tables 1 through 4 to 40 CFR 63 Subpart UUUUU or failed to conduct a required tune-up. These instances are deemed violations from the requirements of 40 CFR 63 Subpart UUUUU and shall be reported according to §63.10031. [§63.10021(g)]

The Permittee shall submit all of the notifications in §§63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h), as applicable, by the dates specified. [§63.10030(a)]

When the Permittee is required to conduct a performance test, the Permittee shall submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin. [§63.10030(d)]

The Permittee shall submit each report in Table 8 to 40 CFR 63 Subpart UUUUU, as applicable. [§63.10031(a)]

The NC DAQ has approved a different schedule for submission of reports under §63.10(a) than the date in Table 8 of Subpart UUUUU. The Permittee shall submit excess emissions and monitoring system performance reports for PM in accordance with the reporting requirements given in Section 2.1.A.7.d no later than January 30 of each calendar year for the preceding three-month period between October and December, April 30 of each calendar year for the preceding three-month period between January and March, July 30 of each calendar year for the preceding three-month period between April and June, and October 30 of each calendar year for the preceding three-month period between July and September. [§63.10031(b)]

The compliance report shall contain the following:

i. The information required by the summary report located in 63.10(e)(3)(vi).
ii. The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or the basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.
iii. Indicate whether the Permittee burned new types of fuel during the reporting period. If the Permittee did burn new types of fuel the Permittee must include the date of the performance test where that fuel was in use.
iv. Include the date of the most recent tune-up for each EGU. The date of the tune-up is the date the tune-up provisions specified in §63.10021(e)(6) and (7) were completed.
iv. A certification.
v. If there is a deviation from any emission limit, work practice standard, or operating limit, the Permittee must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation.
vi. For each excess emissions occurring at an affected source where the Permittee is using a CMS to comply with that emission limit or operating limit, the Permittee shall include the information required in §63.10(e)(3)(v) in the compliance report specified in §63.10031(c). [§63.10031(c) and

§63.10031(d)]

Each affected source that has obtained a Title V operating permit pursuant to 40 CFR Part 70 or Part 71 shall report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 8 of Subpart UUUUU along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. [§63.10031(e)]

On or after April 16, 2017, within 60 days after the date of completing each performance test, the Permittee shall submit the performance test reports required by the Subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). The Permittee shall comply with all applicable requirements in §63.10031(f). [§63.10031(f)]

If the Permittee had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. [§63.10031(g)]

C. Halide Salt Mercury Oxidation Fuel Additives

Duke is requesting to use mercury oxidation fuel additives (halide salt or equivalent additives) applied to the incoming coal to reduce mercury emissions in order to comply with the MATS rule emission limits. Mercury can be found in two forms along the flue gas path: elemental mercury (Hg^0) and oxidized mercury (Hg^{2+}). The oxidized form of mercury is most easily controlled by the existing control devices; therefore, it is desired to convert as much as elemental mercury to the oxidized form and ensure that the material does not revert back to the elemental state to allow for better control device removal efficiencies. Control devices along the flue gas path can alter the oxidation state of mercury and affect the resulting control efficiencies. The selective catalytic reduction (SCR) catalyst contributes to oxidizing mercury from the elemental form to a soluble ionic form, which can readily be captured in the downstream flue gas desulfurization (FGD) scrubber. Duke has determined that oxidation fuel additives may be needed on a periodic basis to ensure that that the mercury is adequately oxidized in the combustion process and captured in the downstream scrubber. Duke states that the MATS mercury emission limits can be met using the current control technologies; however, the oxidation additives will be an "insurance policy" to help ensure compliance with the MATS mercury limits. The additives would be used on an as-needed basis not to exceed 15 gallons per hour for each unit. Duke requested in the application (3600039.15D) that a footnote be added to the Section 1 table of permitted emission sources for the boilers to include a statement that, along with the gallons per hour application rate, the halide salt mercury oxidation fuel additives shall not contain any toxic air pollutants listed in 15A NCAC 02Q .0711. However, it was decided that, as a result of internal comments on the Marshall PM CEMS/MATS/halide salt and renewal permits (being concurrently reviewed along with drafting the same changes for the Allen permit), rather than using a footnote, it would be more proper to incorporate the application rate into the source description for each unit. Since this review documents that Duke has stated that no toxics will be emitted from the halide salt additives, it is not necessary to include the same in the permit.

PM/PM-10/PM-2.5 Emissions and PSD Applicability

For conservatism, PM/PM-10/PM-2.5 emissions are based on assuming the "halide salt" solution is 100% particulate matter, that the highest density product is used, and that it has not reacted in the combustion process. Emissions are reduced by the collection efficiency of the electrostatic precipitator and flue gas desulfurization scrubber. Emissions are calculated as follows:

Application rate	15 gallons/hr
Density	14.1 lb/gallon

Combined collection efficiency (ESP and scrubber)	99.8%
Operation time	8760 hr/yr
Number of units at facility	5

PM/PM-10/PM-2.5 emissions:

$$\frac{tons}{yr} = \left(\frac{15\ gallons}{hr}\right)\left(\frac{14.1\ lb}{gallon}\right)\left(\frac{8760\ hr}{yr}\right)\left(\frac{ton}{2000\ lb}\right)(1-0.998)(5\ units) = 9.26\ tpy$$

The above potential PM/PM-10/PM-2.5 emissions are below the PSD significant threshold emission rates of 25 tpy/15 tpy/10 tpy respectively and therefore PSD review is not triggered.

The revised permit will include a PSD avoidance stipulation to limit PM-2.5 emissions to less than 10 tons per consecutive 12-month period assuming all halide salts introduced in the combustion process are released into the atmosphere. All particulate emissions are assumed to be in the form of PM-2.5 and the avoidance limit will be based upon 10 tons per consecutive 12-month period. The condition (2.1.A.16) includes requirements for monthly emission calculations for PM-25 when applying halide salts with the incoming coal, and associated recordkeeping ((logbook (written or electronic)) and reporting (semi-annual basis).

D. <u>Other Permit Changes</u>

The state-only start-up notification requirement for the Units 4 and 5 DSI ACI storage silo (ID No. ES-U4/5ACISilo) and associated Units 4 and 5 ACI storage silo bin vent filter baghouse (ID No. CD-U4/5ACISiloBf) in Section 2.1.H of the permit was removed the since notification has been made in a letter to Mr. Ron Slack, Supervisor Mooresville Regional Office from P. Brent Dueitt, Allen Responsible Official dated September 1, 2016.

VI. Public Notice

As required by 02Q .0306(a)(11), a draft permit must go to public notice with an opportunity for the public to request a public hearing for a source using an alternative monitoring procedure under 02D .0606. This public notice (30 days) requirement is for a construction and operating permit under 02Q .0300. However, for a Title V permit under 02Q .0501, a significant modification that contravenes or conflicts with a condition in the existing permit, such as the use of PM CEMS in place of COMS, the permit must be processed under 02Q .0501(d)(1) with a 45-day public notice or (d)(2) with a 30-day public notice and submittal of a Title V application before beginning operation and obtaining a permit. There is no advantage to using a 02Q .0501(d)(2) process since Duke already has approval to construct and only needs the Title V operation permit which still requires the 45-day public notice; therefore, the one-step 02Q .0501(d)(1) process is being used with 45-day notice at this time.

Pursuant to 15A NCAC 2Q .0521, a notice of the draft Title V Operating Permit will be published on the DAQ website to provide for a 30-day comment period with an opportunity for a public hearing. Copies of the draft (proposed) permit, review and public notice will be sent to EPA for their 45-day review, to persons on the Title V mailing list, to the Mooresville Regional Office, and to the Permittee for review.

VII. Other Requirements

<u>PE Seal</u>
A PE seal is not required since the application does not involve air pollution capture and control systems in accordance with 02Q .0112.

<u>Zoning</u>
Zoning is not required since there is no expansion of the facility.

<u>Fee Classification</u>
The facility fee classification before and after this modification will remain as “Title V”.

Increment Tracking
Gaston County has triggered increment tracking under PSD for PM-10, SO_2 and NOx. This permit modification will result in an increase in 1.013 pounds per hour of PM-10. This permit modification does not consume or expand increments for SO_2 or NOx.

From Section V.C, emissions of PM-10 are 9.26 tpy for all four units. Therefore, the hourly PM-10 emission rate is:

$$\left(\frac{9.26\ tons}{year}\right)\left(\frac{year}{8760\ hour}\right)\left(\frac{2000\ lb}{ton}\right) = 2.11\ lb/hour$$

VIII. Comments on Draft Permit Prior to Public Notice

The draft permit was sent to Bill Horton at Duke on November 10, 2016. Duke responded on December 7, 2016 with marked-up permit comments. The permit was again sent for Duke's review of the changes as incorporated from the first round of comments. Duke responded on December 14, 2016 with additional comments. Duke responded on December 15, 2016, that they had no further comments on the draft permit prior to public notice. The following summarizes Duke's comments:

1. Comment
   Duke requested a footnote be added to the Section 1, table of permitted emission sources to state that "Incidental spills of oil, antifreeze, etc. that might get on the coal from mobile equipment is allowed to be burned in these boilers."

   DAQ Response
   As discussed internally within DAQ, this can be, and was, added. This is based, in part, on a DAQ memorandum regarding levels of toxic emissions dated May 28, 2004, stating that sources burning not more than 500 gallons per year of on-site generated waste oil are not required to obtain an air permit since the amount of waste oil burned is minimal as compared with the total quantity of fuel typically burned at these facilities. Additionally, it is recognized that on a Btu basis, the burning of spilled waste oil will offset toxics coming from coal to some degree or possibly completely.

2. Comment
   Duke commented that the 02Q .0317(a)(1) PSD avoidance condition, as shown in the regulation table in Section 2.1.A under particulate matter, does not apply to the PM CEMS option that is tied to the more restrictive 0.030 lb/mmBtu limit linked to the MATS UUUUU rule and that the MATS rule should instead be referenced. Also, the footnote to the table should not reference 02Q .0317(a)(1).

   DAQ Response
   The table was revised to indicate that 02D .0536 is the applicable regulation, not 02Q .0317(a)(1) nor the MATS UUUUU rule, for particulate matter when the PM CEMS option is used (which in turn does invoke the MATS UUUUU limits/standards). Also, 02Q .0317(a)(1) was removed from the footnote.

3. Comment
   Duke commented that the in the 02D .0536 monitoring noncompliance statement in Section 2.1.A.4.g for the PM CEMS option, the inclusion of 02Q .0530 is not appropriate as follows:

   > *If the results of the arithmetic 30-boiler operating day rolling average PM CEMS concentration exceeds the limit in this section or any of the above requirements are not met, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0536 ~~or 02D .0530~~.*

   DAQ Response
   DAQ agrees and 02D .0530 was removed.

4. <u>Comment</u>

   Duke requested that, for periods exempted from visible emission monitoring for 02D .0536 (annual average opacity) in Section 2.1.5.a.i, periods of "startups prior to coal firing" be removed and periods of "off-line maintenance" be added since they can no longer bypass during start-up on oil unless it is associated with a malfunction and they included off-line maintenance "just to make sure bypass during periods of off-line maintenance is recognized in the permit." In addition, they requested the condition needs to more clearly reference the calculation of monitor downtime for both compliance options (COMS and PM CEMS).

   <u>DAQ Response</u>

   Periods of "startups prior to coal firing" was removed from the condition as requested. However, periods of "off-line maintenance" was not added since, for compliance purposes, excess emissions during periods off-line maintenance (i.e. when fuel is not being combusted) are handled in accordance with the June 27, 2006 Michael Aldridge memorandum providing guidance for reviewing excess emission reports for 02D .0521 (presumably, this would apply to 02D .0536 as well, as this rule does not exclude off-line maintenance). Paragraph (g) of 02D .0521 states that: *Compliance with the numerical opacity limits in this Rule shall be determined as follows excluding startups, shutdowns, <u>maintenance periods when fuel is not being combusted</u>, and malfunctions approved as such according to procedures approved under Rule .0535*. The guidance concludes that this language pertaining to off-line maintenance is not a blanket exemption, and addresses the fact that if off-line maintenance periods are to be exempted from the limits in 02D .0521, they must, as paragraph (g) states, be "approved as such according to procedures approved under 02D .0535 …" However, the guidance points out that off-line maintenance (or maintenance periods when fuel is not being combusted) is not specifically described in 02D .0535. Therefore, even though 02D .0521 requires off-line maintenance to be approved under 02D .0535, it is not described in 02D .0535 and therefore the guidance covers the provisions that would logically apply to such situations.

   Also, the condition was revised to more clearly reference the calculation of monitor downtime for both compliance options.

5. <u>Comment</u>

   Duke requested they be allowed a limit of 10% for the percent monitor downtime (%MD) in Section 2.1.A.7.b for the initial year of using the PM CEMS rather than the standard 2% per previous agreement with Stationary Source Compliance Branch (SSCB). Also, they claimed this is consistent with the language in the Belews Creek and other Progress permits (Roxboro and Mayo) issued for PM CEMs.

   <u>DAQ Response</u>

   DAQ could not find any such agreement with SSCB. In addition, the higher 10% allowance is not in the Belews Creek or Mayo permits. It is in Roxboro, but that appears to be an error back in 2010 related to monitor availability not MD. The Roxboro permit states:

   > *… these sources shall be deemed to be properly operated and maintained if the %MD does not exceed 25 percent (10 percent beginning on January 1, 2012) for any given calendar quarter as calculated below. However, if %MD is less than 25 percent (10 percent beginning on January 1, 2012) but greater than 2 percent, the Permittee shall provide a full explanation to DAQ in the quarterly report including actions taken to reduce monitor downtime below 2%.*

   As compared to compliance provisions in NSPS 60.48Da(p)(5) that states:

   > *At a minimum, non-out-of-control CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30-boiler operating day rolling average basis. Beginning on January 1, 2012, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-boiler operating day rolling average basis.*

   Therefore, no change to the condition was made.

6. Comment
Duke requested the permit be revised so that, as an alternative to meeting the MATS emissions limits in §63.9991(a)(1) for filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis as described in Section 2.1.A.15.a, they may choose to demonstrate compliance by using emissions averaging as described in §63.10009(a)(2) among existing EGUs in the same subcategory.

DAQ Response
The alternative emissions averaging option was added at Sections 2.1.A.15.c, v and hh.

7. Comment
Duke requested, where the permit states that all continuous monitoring systems (CMS) must be operated in Section 2.1.A.15.d.i (Section 2.1.A.13.c.i in the draft permit) during startup and Section 2.1.A.15.e.i during shutdown, it be clarified that the exception during periods of bypass of the main stack as provided in §63.10010(a)(4), be added and that all periods of bypass of the main stack shall be reported as deviations as provided in §63.10010(a)(4)(ii).

DAQ Response
DAQ agrees that the provisions in §63.10010(a)(4) clearly provide that during bypass of the main stack, where there are no CEMS on the bypass stack, one option, as an exception to operating a CMS during startup and shutdown, allows for the installation of a CEMS (one type of CMS) only on the main stack and count hours that the bypass stack is in use as hours of deviation from the monitoring requirements. Therefore, this change was made.

8. Comment
Duke wanted confirmation that SNCR NOx control is not an applicable MATS control technology as referenced in Section 2.1.A.15.d.i. (taken from Part 63 Subpart UUUUU Table 3) where it states:

> *The Permittee shall operate all CMS during startup, except during periods of bypass of the main stack as provided in §63.10010(a)(4). For startup of a unit, clean fuels must be used as defined in §63.10042 for ignition. Once the unit converts to firing coal, the Permittee shall engage all of the applicable control technologies except the SCR. The Permittee shall start the SCR system appropriately to comply with relevant standards applicable during normal operation.*

Duke states this makes sense that it is not an applicable control technology given the Allen permit source/control device description table footnote, which reads:

> *The ammonia and sulfur trioxide ash conditioning and NOx systems (includes SNCR) may be operated independently of each other or in combination. Each system may be operated intermittently as necessary, based on the boiler system requirements, to maintain compliance with the applicable emission standards.*

DAQ Response
Duke was informed that DAQ sees no reason a SNCR would not be an applicable NOx control technology under MATS UUUUU. It is part of the rule in §63.10021(e)(6).

Follow-up Comment
Duke states that they "…do not think the MATs rule precludes operation of NOx controls as identified in our permits. We will seek confirmation SNCR NOx control is not an *applicable* MATS control technology as referenced in Part 63 Subpart UUUUU Table 3 3." Also, Duke states: "We will likely need to reach out to the Air Program Group and we may need to obtain input from UARG/ H&W regarding the need to engage an SNCR when starting on oil. In Allen's case under the Consent decree the SNCR for Consent Order applicable units must be engaged at all times."

DAQ Follow-up Response
DAQ believes, unless Duke can verify differently, that SNCR appears to be an applicable NOx control

technology under MATS UUUUU. Where the rule (see above) states that once the unit converts to firing coal during startup, all of the applicable control technologies except the SCR are to be engaged and that the SCR is to start appropriately to comply with relevant standards, the SCR is evidently not required to be engaged immediately because SCRs are not operable until the catalyst reaches an elevated temperature. It is not believed there are any similar restrictions on operating a SNCR.

9. Comment
   Duke requested clarification be added (as underlined below) to Section 2.1.A.16 to state that calculations of $PM_{2.5}$ emissions from applying halide salt mercury oxidation fuel additives to the incoming coal in the boilers (ID Nos. ES-1 through ES-5) shall be made and recorded in a logbook (written or electronic format) at the end of each month when the additives have been used.

   DAQ Response
   This change was made.

The draft permit was sent to Joe Foutz at MRO on January 13, 2017 for review. MRO responded on January 24, 2017, that they had no comments.

The draft permit was sent to Samir Parekh with SSCB on January 13, 2017 for review. No comments were received from SSCB.

IX. Recommendations

After public notice…..